Service Date: February 23, 1977

BEFORE THE UTILITY DIVISION
DEPARTMENT OF PUBLIC SERVICE REGULATION
MONTANA PUBLIC SERVICE COMMISSION

IN THE MATTER OF the Petition of THE MONTANA POWER COMPANY for Increased Rates and Charges in Gas and Electric Service.	)	UTILITY DIVISION DOCKET NO. 6348 ORDER NO. 4220C

APPEARANCES:

ROBERT D. CORETTE, Attorney at Law, 40 East Broadway, Butte, Montana, appearing on behalf of the Applicant.

JOHN J. BURKE, Attorney at Law, 40 East Broadway, Butte, Montana, appearing on behalf of the Applicant.

MARK A. CLARK, Attorney at Law, 40 East Broadway, Butte, Montana, appearing on behalf of the Applicant.

PROTESTANTS

GEOFFREY L. BRAZIER, Montana Consumer Counsel, 34 West Sixth Avenue, Helena, Montana, appearing on behalf of the consuming public of the State of Montana.

WILLIAM E. O'LEARY, Attorney at Law of the firm of Risken and O'Leary, P. O. Box 225, Helena, Montana, appearing for the Montana Consumer Counsel.

INTERVENORS:

WILLIAM G. STERNHAGEN, Attorney at Law, 1625 Eleventh Avenue, Helena, Montana, appearing on behalf of the Anaconda Company.

JAMES A. ROBISCHON, Attorney at Law of the firm of Poore, McKenzie, Roth, Robischon and Robinson, Suite 400, Silver Bow Block, Butte, Montana, appearing on behalf of the Anaconda Company.

TOM BURTON, Attorney at Law, P. O. Box 2197, Houston, Texas. appearing on behalf of Continental Oil Company.

C. W. LEAPHART, JR., Attorney at Law, 1 Last Chance Gulch, Helena, Montana, appearing on behalf of Hoerner-Waldorf Company.

C. S. McCRACKEN, Attorney at Law, 302 Great Falls National Bank Building, Great Falls, Montana, appearing on behalf of Great Falls Gas Company.

ALAN F. CAIN, Attorney at Law of the firm of Hughes, Bennett and Cain, P. O. Box 1166, Helena, Montana, appearing on behalf of Ideal Cement Division, Ideal Basic Industries.

CAPTAIN DOUGLAS "CHIP" RAWLINGS, Attorney at Law, Malmstrom Air Force Base Great Falls, Montana, appearing on behalf of the Executive Agencies of the United States Government.

ARTHUR THOMAS, Attorney at Law, Malmstrom Air Force Base, Great Falls, Montana, appearing on behalf of the Executive Agencies of the United States Government.

WARREN McCONKIE, Malmstrom Air Force Base, Great Falls, Montana, appearing on behalf of the Executive Agencies of the United States Government.

DON R. LEE, Attorney at Law, Shelby, Montana, appearing on behalf of Consumers Gas Company and Treasure State Pipe Line Company.

DOROTHY BARR, 115 Reed Avenue, Helena, Montana, appearing on behalf of the Montana State Low Income Organization.

CEDOR B. ARONOW, Attorney at Law, Shelby, Montana, appearing on behalf of the Shelby Gas Association.

FOR THE COMMISSION STAFF:

RUSSELL L. DOTY, JR., Counsel

ALAN ROTH, Attorney at Law of the firm of Spiegel and McDiarmid, 2600 - Virginia Avenue N. W., Washington, D. C., appearing for the Commission.

FOR THE COMMISSION:
WILLIAM J. OPITZ, Administrator, Utility Division
DENNIS CRAWFORD, Deputy Administrator, Utility Division
FRANK E. BUCKLEY, Analyst, Utility Division

BEFORE:
GORDON E. BOLLINGER, Chairman

P. J. GILFEATHER, Commissioner

THOMAS G. MONAHAN, Commissioner

JAMES R. SHEA, Commissioner

GEORGE TURMAN, Commissioner

FINDINGS OF FACT

PART A
GENERAL

1. The Montana Power Company (Applicant, MPC, or Company) is

a public utility furnishing water, electric and natural gas service to consumers in the State of Montana.

2. This Commission has jurisdiction over the rates and charges for, and the conditions under which, utility service is rendered in Montana.

3. Docket No. 6348 is the result of consolidation of the matters pending in three other Commission dockets, numbers 6279, 6327 and 6336.

4. Pending in Docket No. 6348 are:

(a) the Applicant's Petition requesting approval of rate schedules and contract rates and certain service conditions, filed March 12, 1975, in Docket No. 6279 and amended July 18, 1975; and

(b) Applicant's request for increased gas rates to offset increased gas supply costs filed June 25, 1975, in Docket No. 6327.

5. Applicant's amended Petition requests Commission approval of rates for electric utility service which are designed to produce an increase in annual gross operating revenues of $15,650,601 during the test year.

6. Applicant's amended Petition requests Commission approval of rates for natural gas service which are designed to produce an increase in annual gross - operating revenues of approximately $28,800,000 during the test year, of which approximately $22,251,442 is requested to offset increased gas supply costs and approximately $6,500,000 is requested to meet all other increased costs of service.

7. The Montana Consumer Counsel (MCC) has participated on behalf of utility consumers in this docket since the inception of these proceedings.

8. On August 5, 1975, a notice of public hearing was duly issued by this Commission scheduling a public hearing in this docket to commence on September 8, 1975. On August 29, 1975, this Commission vacated the hearing schedule. On d September 22, 1975, this Commission duly issued a second notice of public hearing in this case rescheduling public hearings to commence on October 20, 1975.

9. Both the August 5 and September 22, 1975, notices of public hearing were published in several newspapers of general circulation in the State of Montana.

10. No objection has been made to the adequacy or form of the September 22, 1975, notice or to the manner or times of its issuance and publication.

11. Public hearings in this docket were conducted by the Commission in Helena, Montana, from October 20 to November 6, 1975; from January 12 to January 23, 1976; and from February 2 to February 13, 1976.

12. Individual Commissioners conducted public hearings in this docket in the following Montana cities at which persons appeared and testified or submitted statements: on November 24, 1975, in Kalispell, Billings and Butte; on November 25, 1975, in Butte, Havre and Missoula; on November 26, 1975, in Great Falls and Glasgow; on November 28, 1975, in Bozeman; and on December 19, 1975, in Lewistown a public hearing was convened at which no person appeared.

13. At the hearing conducted in Helena, Montana, the Commission heard the testimony of fifty-four witnesses and accepted ninety-three exhibits during the course of direct and cross-examination by members of the Commission, the Commission staff, the Applicant, MCC, and the intervenors Anaconda Company, Great Falls Gas Company, Hoerner-Waldorf Company, Ideal Cement Company, and the Executive Agencies of the United States Government.

14. On July 26, 1976, MPC filed a Motion for temporary rate increases in gas and electric service, together with a Petition to present additional testimony in this docket, which testimony allegedly would have shown the need for immediate rate relief. The July 96 Petition was denied because the proposed testimony would have resulted in a reopening of the evidentiary record in this docket, and because the testimony would have been irrelevant and prejudicial as it would have dealt with post-test year data.

15. The July 26, 1976, Motion was set for argument on August 12, 1976. At that time the Applicant, by argument of its counsel, discussed the merits of the testimony of various parties in this proceeding in seeking immediate rate increases. Applicant also made an offer of proof, which consisted of the affidavits of J. J. Harrington and J. W. Heidt and which was allegedly "submitted for the sole purpose of establishing the necessity of prompt Commission action on the Motion for temporary rate increases." The offer of proof was rejected by Commission ruling as it violated the Commission's minute entry of July 27, 1976, limiting the August 12, 1976 hearing to legal argument, and because the material contained therein was irrelevant to any issue in this docket.

16. Under the Commission's order regarding briefs, and because of unavoidable delay in the preparation of the transcript, this case was not submitted for decision until December 13, 1976.

17. On January 6, 1977, the Commission issued Order No. 4220B in this docket. This order granted MPC a temporary increase it its natural gas rates.
The order also denied Applicant's Motion for a temporary rate increase for electric service, and denied the MCC Petition for an electric rate decrease, Docket No. 6336. The denial of the MCC Petition is affirmed by this Order. Reasons for the denial are contained in Parts C and E of this Order.

18. Applicant proposes that calendar year 1975, adjusted to reflect known changes and normalization of non-recurring conditions, be used as a test period in this docket.
19. A test year 1975 is a reasonable period within which to measure Applicant's utility revenues, expenses and return for the purpose of determining a fair and reasonable level of rates for electric and natural gas service.

PART B
RATE OF RETURN
Capital Structure

20. Applicant sought a December 31, 1975, capital structure for the consolidated company as follows:

Type	Amount	Amount of Capitalization
Long-Term Debt	$289,481,000	50.18%
Preferred Stock	21,617,000	3.75%
Common Equity	246,361,000	42.70%
Deferred Taxes	19,439,000	3.37%
Total	$576,898,000	

(Proposed Finding No. 96)

21. Staff Witness Dr Wilson determined a July 31, 1975, capital structure as follows:

Type	Amount	Amount of Capitalization
Long-Term Debt	$310,027,152	58.094
Preferred Stock	21,617,083	4.051
Net Common	202,020,614	37.855
Total	$533,664,849	

(Exhibit A-23,,Schedule 36)

Wilson's rationale for the use of July 31, 1975, figures was that these were the latest available to him at the time he prepared his testimony. The preferred stock component utilized in the above table represents the modified component conceded by Dr. Wilson on rebuttal to be accurate.

22. Dr. Phillips, MPC's primary rate of return witness, presented alternative approaches to the problem of capital structure. He presented Applicant's capital structure on a consolidated basis for the entire company, including its non-utility subsidiaries (Exhibit 2, Schedule 22, p. 2, A), and he presented an allocated structure which

had the effect of isolating Applicant's electric and gas utility operations as if they were separate companies (Exhibit 2, Schedule 22, p. 2, B and C). In attempting to determine the proper capital structure for a regulated company, it is desirable that capital related to unregulated enterprises such as Big Sky, Altana, and Western Energy, be eliminated. Dr. Wilson attempted to do this although the manner in which he proceeded is unclear and is not demonstrated on the record. Accordingly, the Commission finds that Dr. Phillips' allocated capital structure best presents the electric and gas capital structures apart from MPC's investments in unregulated enterprises.

23. Phillips offered revised schedules 22 and 26 of Exhibit 2 which incorporated certain revisions to Applicant's capitalization suggested by Mr. Raff (Tr. 1067). These related to changes occurring after the original testimony was filed. The basis for these changes is shown in Exhibit E, Mr. Woy's work papers (work paper no. 4), and in Exhibit No. 20, Dr. Phillips' work paper (page 3 of 4). Exhibit 20 shows the totals resulting after adjustment of the Exhibit 2, Schedule 22, capital components for known changes in each component. These changes included:

(a) Common equity -- A $12,081,000 increase in retained earnings and capital surplus, and a $38,250,000 common stock sale in July of 1975. The resulting $50,331,000 is an increase in equity for the consolidated company.

(b) Preferred stock -- This component remained the same.

(c) Long-term debt -- This component increased because of the net effect of a July, 1975, bond sale of $35,000,000; the refunding of $39,188,000 of 2-7/8 percent bonds effective October 1, 1975; addition of $9,000,000 notes to Bond-Lone Star Gas Company; addition of a S9,200,000 increase in pollution control bonds released by the trustee, less net of 5949,000 of debt discount and expense and debenture redemptions; and an increase of $37,000,000 for a Western

Energy term loan. The total increase in debt for the consolidated company resulting from these known changes was $50,063,000.

24. The revisions discussed in Finding No. 23, when allocated to the electric and gas operations on the basis of net utility plant, as described in Exhibit 20, p. 3 of 4, resulted in the following capital structures:

Electric	Amount	Percent of Capitalization
Long-Term Debt	$176,879,000	46.8%
Preferred Stock	16,967,000	4.5%
Common Equity	167,082,000	44.3%
Tax Deferrals	16,566,000	4.4%
Total	$377,494,000	100.0%

Gas		
Long-Term Debt	$ 51,241,000	47.8%
Preferred Stock	4,447,000	4.2%
Common Equity	50,548,000	47.2%
Tax Deferrals	845,000	.8%
Total	$107,081,000	100.0%

25. On December 10, 1975, Applicant sold S65,000,000 of 9.7 percent bonds (Tr. 5921).

26. This increase in Applicant's debt component, when allocated to the electric and gas operations on the basis of net utility plant, results in an increase in electric debt of $51,025,000, and in gas debt of $13,390,000.

27. Inclusion of the December 10, 1975, debt issue results in the following allocated capital structures:

Electric	Amount	Percent of Capitalization
Long-Term Debt	$227,904,000	55.32%
Preferred Stock	16,967,000	4.12%
Common Equity	167,082,000	40.56%
Gas		
Lonq-Term Debt	$ 64,631,000	54.03%
Preferred Stock	4,447,000	3.72%
Common Equity	50,548,000	42.25%

28. Tax deferrals have been eliminated from the capital

structure as they have been treated in the Commission's determination of rate base. See discussion below in Findings 49 and 50.

29. In order to arrive at the capital structure which the Commission ultimately finds to be appropriate in this proceeding, it is necessary to deduct from the equity portion of the electric capital structure $5,939,000 of original cost depreciated acquisition adjustments, and the $2,800,000 elimination of FPC's fair value determination for the Mystic Lake property, as discussed below in Findings 42 and 46. This results in the following capital structures:

Electric	Amount	Percent of Capitalization
Long-Term Debt	$227,904,000	56.52%
Preferred Stock	16,967,000	4.21%
Common Equity	158,343,000	39.27%
Gas		
Long-Term Debt	$64,631,000	54.03%
Preferred Stock	4,447,000	3.72%
Common Equity	50,548,000	42.25%

30. The debt component of Dr. Wilson's capital structure is rejected, as the Commission finds that the structure in this case must include the December 10, 1975, bond issue, and must reflect the retirement of the 2-7/8 percent bonds. Wilson also included $45,000,000 of Western Energy debt, which the Commission finds inappropriate in view of its exclusion of all non-utility capital. Wilson failed to adjust his structure for the other post-July 31, 1975, changes discussed in Finding No. 23, and these revisions have been incorporated as they constitute actual changes in Applicant's test year capitalization.

Cost of Debt

31. The Company's determination of the embedded cost of debt to the electric and gas utilities of 7.84 percent and 7.74 percent (Exhibit 2, Schedule 22, p. 2 of 2, as revised), respectively, is accepted subject to adjustment for the December bond issue of $65,000,000. This adjustment

results in a cost of debt to the electric utility of 8.26 percent, and to the gas utility of 8.15 percent.

Cost of Preferred Stock

32. The cost of preferred stock, as determined by both staff and Company witnesses, is 5.6 percent for both utilities.

Cost of Equity

33. Applicant's major rate of return testimony was presented by Dr. Phillips. He relied exclusively on a comparable earnings approach to determine Applicant's cost of equity capital. He reasoned that only by examining returns available on alternative investments, with risks comparable to that on the MPC stock, could a realistic judgement of the return required hy investors be made. To determine these "comparable earnings," Phillips examined two groups of unregulated companies, Moody's 125 Industrials and Standard and Poor's 425 Industrials, as well as Moody's 24 Utilities. He concluded that Applicant's return for the test period fell below the average for either of these industrial groups. Phillips recommended a return on equity of 14.5 to 15 percent for the electric utility and 15 to 15.5 percent for the natural gas utility because of the greater risk in that portion of the business. 34. Dr. Wilson utilized both a comparable earnings and a discounted cash flow (DCF) approach in arriving at his recommended return on equity. Wilson examined a broader spectrum of companies than did Dr. Phillips, reflecting the many alternatives available to an investor in his choice of a desirable investment. Having formulated a judgement as to the returns earned by comparable enterprises, Wilson supplemented his analysis with DCF calculations. DCF is an investor-oriented approach, which rests on the theory that the maximum price that an investor will pay for a security is an amount equal to the present value of the dividends that he expects to receive over the years which he holds the security plus its resale price, including capital gains, when he sells it. (Tr.3069-3070) Wilson concluded that, based on both approaches, a return exceeding 11.25 percent for the electric utility, and 12

percent for gas was not required.

35. Dr. Phillips argued that utilities, even though they have a lower overall business risk than industrial companies, represent a greater risk to equity holders than do industrials. He rested this conclusion on the fact that utilities have a higher debt component than industrials, with equity holders receiving only that portion of earnings remaining after payment of fixed charges.
This argument ignores, however, Applicant's exceptionally high equity components.
Applicant's 39.27 percent electric utility equity ratio, and 42.25 percent gas equity ratio, compare to an average equity ratio of 35 percent for the entire utility industry (Tr. 906). Furthermore, utility investors have the advantage of stable earnings and stable dividend growth rates (Tr.3067).

36. Phillips criticized Dr. Wilson's use of the weighted average dividend growth rates of his comparison companies in making his DCF calculation (Tr. 4864). Phillips argued that the use of growth intangible book value per share would have produced a better result (Tr. 4865). On rebuttal, however, Dr. Wilson presented the results of a DCF analysis which utilized growth in tangible book value, and the results supported his original recommendation (Tr. 6135).
37. Applicant's witness Raff argued that a 15 percent return on equity was necessary to attract capital (Tr. 883). This testimony was based more on opinion than on a reasoned analysis, and was refuted by the fact Applicant successfully financed several times in the 1974-1975 period with a return on equity below 15 percent.

38. Witness Meyer testified that Applicant's requested return constituted no more than the bare cost of capital in the money markets (Tr. 5436). He suggested that the prospect of dilution has driven investors from the utility common market. This remark was contradicted by testimony concerning the Wall Street Journal's comment that the July, 1975, MPC common

stock issue was "gobbled up" by investors (Tr. 1242).

39. The Commission finds that a return of 11.25 percent for the electric utility, and of 12 percent for the gas utility is appropriate. As pointed out by Dr. Wilson, Applicant is in the desirable position of having a guaranteed fuel supply from its Western Energy subsidiary. This is an important factor from the standpoint of the investor, in that it minimizes the risk inherent in Applicant's operations. This point was recognized by both Mr. Raff (Tr. 993) and Dr. Phillips (Tr. 4342).

40. Based on Findings 27, 28, 29, 31 and 39, the Commission finds the following capital structure, with the associated cost of each component, to be appropriate:

Electric	Amount	Percent of Capitalization	Embedded Cost	Weighted Cost
Long-Term Debt	$227,904,000	56.52%	8.26%	4.67%
Preferred Stock	16,967,000	4.21%	5.60%	.24%
Common Equity	158,343,000	39.27%	11.25%	4.42%
Overall Return				9.33%
Gas				
Long-Term Debt	$64,631,000	54.03%	8.15%	4.40%
Preferred Stock	4,447,000	3.72%	5.60%	.21%
Common Equity	50,548,000	42.25%	12.00%	5.07%
Overall Return				9.68%

PART C

ELECTRIC UTILITY
Rate Base

41. The Commission finds the following electric utility rate base:

1975 Test Year (Average)
(000)

	12/31/74 (A)	12/31/75 (B)	1975 C)
1. Depreciated Original Cost			
2. Electric Plant (Exh. 12, line 7)	$239,253	$330,660	$
3. Common Plant (Exh. 12, line 10)	5,727	6,948	
4. Total Net Plant	244,980	337,608	291,294
5. Adjustments to Net Plant			
6. Eliminate "Value" Recorded on Books in Excess of Original Cost			
7. Mystic Lake	(2,102)	(2,102)	
8. Include Colstrip #1 for Full Year			
9. Production Plant	71,782		
10. Transmission Plant	761		

11. Adjust Depreciation Reserve	-	571	
12. Total Adjustments to Net Plant	70,441	(1,531)	34,455
13. Less: Customer-Contributed Capital			
14. Accumulated Deferred Income Taxes			
15. Accelerated Amortization	2,142	2,066	
16. Liberalized Depreciation	12,101	15,312	
17. Accumulated Deferred Investment Tax Credits (Pre-1971)	1,686	1,604	
18. Customer Advances for Construction	598	600	
19. Total Customer-Contributed Capital	16,527	19,582	18,054
20. Plus: Working Capital			
21. Gross Cash Requirements			3,324
22. Credit for Accrued Taxes			(4,616)
23. Fuel			1,455
24. Materials and Supplies			3,981
25. Total Working Capital			4,144
26. Total Electric Utility Rate Base			$311,839

42. The depreciated original cost values shown in lines 2 and 3 of the above table do not include amounts recorded in Accounts 114 and 116 of the NARUC Uniform System of Accounts, by which Applicant maintains its books of account. The Commission's order in Re The Montana Power Co., 56 P. U. R. (n.s.) 193 (1944), directed that a total of 56,070,402 be placed in these two accounts. The present net amount in these accounts is $5,939,000. This amount is the difference between the cost to Applicant of various properties and the original cost of those properties when first dedicated to public use. The totals in these two accounts have been excluded from rate base because, by definition of the accounts, they represent an investment which exceeds original cost.

43. Witness Hess urged the Commission to eliminate an additional $15,722,000 of electric rate base (Tr. 2751-2752). After the elimination of acquisition adjustments discussed in Finding No. 42, this is the amount by which Applicant's electric rate base still exceeds the original cost determination of the Federal Power Commission in Re The Montana Power Co., 4 F. P. C. 213, 57 P. U. R. (n.s.) 143 (1945). Because of the questionable nature of the adoption by the Montana Commission in its 1944 opinion of the concept "commercial value" (Tr. 2751), inclusion of this amount in an original cost depreciated rate base remains a matter of continuing concern. However, because the record in

this docket is very limited on this point, the Commission declines to eliminate the difference. To deal with the problem in future proceedings, the Commission directs Applicant to take the action contained in Order paragraph 4.

44. The Commission finds that an average rate base is appropriate in this proceeding. As explained by Witness Hess, since the rate base increases during the year, an allowed return calculated on a year-end basis overstates the return on the amount actually at risk during the test period. Because revenues and expenses are affected by increases in plant, the revenues and expenses of the test year are not those that were produced by the year-end plant (Tr. 2742). Proper rate-making requires that the test year revenues and expenses realistically reflect expected performance under the test year base. The fact that this order is issued after the end of the test year does not alter this requirement.

45. Applicant's witness Carver contended that the attempt to synchronize test year revenues and expenses with the property which produced them by means of average rate base is a "meaningless objective." Carver recognized, however, that the Commission has an obligation to relate revenue requirements to actual costs (Tr. 5568), and the Commission feels this is best accomplished by the use of average rate base.

46. Applicant included in its original cost figures in Exhibit 12 the valuation of its Mystic Lake hydroelectric project as fixed by the Federal Power Commission (FPC). A December 9, 1974, FPC order determined the fair value of this project to be S2,800,000 in excess of its original cost. This fair value determination was made in compliance with Section 23(a) of the Federal Power Act (Tr. 2746). The amount eliminated from rate base is $2,102,000, which is the present net value by which this amount exceeds

47. The Applicant's pro forma adjustments to test year revenues and expenses depicted the Colstrip #1 generating plant and related transmission facilities as being in service during the entire test year. Therefore, the beginning test year rate base balance must be adjusted to reflect this assumption (Tr. 2741-

2742).

48. The adjustment to depreciation reserve is necessitated by certain adjustments to depreciation expense. These are discussed below in Finding No. 57, and relate to Colstrip Unit 1 and other 1975 additions to electric plant (Tr. 2753-2754)

49. The Applicant sought to include certain amounts of customer contributed capital in the rate base. All such capital must be excluded from the rate base because it is not the role of the ratepayer to advance portions of capital necessary to construct or maintain utility plant. The following customer-contributed capital has been excluded accumulated deferred income taxes, accumulated deferred investment tax credits, and customer advances for construction (Tr. 2754, 2755 and 2756). The deferred taxes arise as a result of the Applicant's normalization of the tax effects of accelerated amortization and liberalized depreciation. The tax credits likewise arise from MPC's normalization of its income tax charges to eliminate the effect of current investment tax credits and their amortization over the life of the property to which they relate. Exclusion of customer advances is consistent with the concept that there must be a matching of plant investment with the revenues which such investment might ordinarily be expected to generate. As witness Hess pointed out, even though refunds of advances are constantly being made, now advances replace them in what Hess described as "a revolving fund" (Tr. 2756-2757).

50. Dr. Phillips treated tax deferrals as a zero cost component of his capital structure (Tr. 1106), and Applicant argues that this approach is preferable to the Hess approach of treating tax deferrals as a rate base deduction (Applicant's Opening Brief, pp. 20-22). Phillips testified on cross-examination that deduction of deferrals from rate base is an accepted regulatory approach (Tr. 1265). Because deferrals are used to acquire assets, the Commission finds that the approach which treats them in conjunction with rate base is more logical.

51. With respect to the determination of allowance for working

capital, the Commission finds as follows:

A. The gross cash requirement is calculated as 1/8th of the sum of operation and maintenance expenses, plus property taxes less purchased power and fuel. The reason for the exclusion of fuel is that, like purchased power, it is a major item of expense for which there is a substantial lag in the payment thereof by the Applicant. Property taxes must be included to reflect the post payment of such taxes (Tr. 2757).

B. There must be included in working capital a credit for accrued taxes, which is referred to as negative working capital. The negative capital is included because some of the funds which the - Applicant collects to pay property taxes are received long before the taxes are paid over to the taxing authorities. It is apparent that, since these taxes are postpaid, the Applicant has the use of such funds between the time they are received from the customer and the time they are paid. These property taxes are payable in November of the current year and in May of the following year. and with that payment schedule, the Applicant has available on the average approximately 60 percent of the test year property tax accrual (Tr. 2757).

C. Consistent with the average rate base approach, the calculation of the allowance for materials and supplies must be the actual average balance. The actual average balance for the 12 months ended October. 1975, is used because it represents the latest figures available to witness Hess when he prepared his exhibits. The Commission can not use more recent information, as none is contained in this record.

Revenues and Expenses

52. Applicant claimed test year electric operating revenues of $76,616,000 (Exhibit 14).

53. Revenues from surplus sales to other utilities must be adjusted

by $1,157,000, computed as follows:

(000)

1.	1975 Test Year Surplus Sales..................	462,864 Mwh
2.	Revenues on Surplus Sales @ 7.5 mills per kwh......................................	$3,471
3.	Revenues per Company..........................	2,314
4.	Adjustment to Revenues	$1,157

54. In the first eleven months of 1975, Applicant sold 735,000 Mwh of electricity to other utilities, earning S5,430,843 of revenue. This is an average price of 7.38 mills per kwh (Tr. 2762). This price contrasts with the MPC estimate of 5 mills per kwh. Use of the 7.5 mills figure, which is based on prices testified to by Witness Hess, results in the adjustment shown in Finding No. 53.

55. The Commission finds that the revenues Applicant receives from its sales not subject to the jurisdiction of this Commission do not result in an adequate return on investment. If these sales are not to be subsidized by Applicant's ratepayers, a revenue adjustment is necessitated. The revenue deficiency and required revenue adjustment are calculated as follows:

(000)

1.	Utility Operating Income at Present Rates per Company (Exhibit 14)............................	$ 25,285
2.	Depreciated Original Cost Rate Base per Company (Exhibit 12)..............................	352,874
3.	Rate of Return Earned per Company.................	7.17%
4.	Depreciated Original Cost Rate Base Allocated to Non-Jurisdictional Sales per Company..............	13,651
5.	Allowable Return of 6%...............................	819
6.	Actual Return per Company............................	393
7.	Non-Jurisdictional Income Deficiency (after tax)......	426
8.	Non-Jurisdictional Revenue Deficiency and Adjustment...	$879

56. A revenue adjustment is necessary to recognize the additional revenues which Applicant will realize from renegotiated contracts for service to Malmstrom and Glasgow Air Force bases. These new contracts will result in increased revenues of approximately $87,000 (Tr. 5805;Exhibit 41).

57. A. Applicant urged that its 1975 test year depreciation expense should be calculated on the basis of estimated plant in service at the end of 1975. However, Applicant determines depreciation expense for book purposes on the basis of plant in service at the beginning of the year. As a consequence, the depreciation expense claimed for rate-making purposes in this docket is more closely related to what will be booked for 1976 than for 1975 because it is based on plant in service at the beginning of 1976. So that 1976 expenses and 1975 test year revenues are not mismatched, it is necessary to subtract the

amount MPC included for depreciation expense on 1975 additions to plant.

B. The depreciation expense which Applicant sought on value in excess of the original cost of the Mystic Lake project must be similarly eliminated.

C. Finally, the depreciation expense on Colstrip #1 generating unit and related transmission plant must be added to Applicant's claimed depreciation expense to be consistent with the adjusted 1975 test year figures (Tr. 2767-2769). The adjustment to the 1975 test year depreciation expense is summarized by the following schedule:

	000)	
1.	Depreciation Expense Claimed (Exh. 14, line 19)	$7,779
2.	Less:	
3.	Depreciation Expense on 1975 Additions	
4.	Electric Plant	$2,417
5.	Less Yellowstone National Park	4
6.	Electric Plant - Montana	2,413
7.	Common Plant	45
8.	Total	(2,458)
9.	Depreciation Expense on "Value in Excess of Original Cost of Mystic Lake (50)	
10.	Add:	
11.	Depreciation Expense on Colstrip #1	
12.	Production Plant	1,925
13.	Transmission Plant	12
14.	Total	1,937
15.	Adjusted Depreciation Expense	$7,208
16.	Adjustment to Depreciation Expense	(571)

The corresponding adjustment to depreciation reserve for purpose of rate ; base is shown in Finding No. 41, line 11.

58. A. Applicant sought to include an allowance for real estate and personal property taxes for a full year of 1975 additions. This approach is inconsistent with average rate base. Therefore, one-half of the taxes on test year 1975 additions other than Colstrip #1 and related transmission facilities must be eliminated.

B. In view of the additional revenues resulting from the adjustments made in Findings 53, 54, 55 and 56, the gross proceeds tax must be adjusted

C. Based upon the pro forma adjustment by MPC, accepted by Consumer Counsel, assuming Colstrip Unit 1 in service for the entire year 1975, an adjustment must be made to Applicant's income tax calculations, which reflected only one-half year's depreciation on this property. Additionally, the federal income tax effect of the additional straight line tax depreciation that would have been available, and the additional provision for deferred federal income taxes if this property were in service for the full year 1975, must be depicted.

59. The foregoing tax expense adjustments are summarized in the

following table:

(000)

1. Gross Proceeds		
2. Revenue Adjustments	$2,123	
3. Revenue Taxes at 1.688%		$36
4. Real Estate and Personal Property Taxes		
5. Included in Exhibit 14	10,051	
6. Company Revised Estimate (12/19/75)	8,546	
7. Adjustment		(1,505)
8. Eliminate One-Half of Taxes on Full Year 1975 Additions Excluding Colstrip #1		(852)
9. Total Adjustments to Taxes Other than Income Taxes		$(2,321)
10. Income Taxes		
11. Adjustments to Revenues	$ 2,123	
12. Income Tax Effect of Adjustments to Revenues		1,019
13. Adjustments to Other Taxes 2,321		
14. Income Tax Effect of Adjustments to Other Taxes		1,114
15. Additional Straight Line Tax Depreciation Assuming Colstrip #1 in Service Full Year	1,143	
16. Income Tax Effect of Additional Colstrip #1 Tax Depreciation		(549)
17. Total Adjustments to Income Taxes		$1,584

60. Applicant's operating revenue figures failed to include the profit which it realized upon the reacquisition of its debt at a discount. Nor was this amount taken into account by other witnesses in their computations of the cost of debt. Witness Hess contended that an adjustment to revenues should be made to recognize this profit (Tr. 2774), and the Commission finds that electric operating revenues must be increased by $114,000 to reflect the amortization of this profit on debt reacquired at a discount.

61. Provision for deferred federal income taxes must be increased by $811,000 to reflect the assumption that Colstrip Unit 1 was on line for the entire test period (Tr. 2773).

62. The following table summarizes the Commission's findings as to revenues, expenses, and rate of return under present electric rates:

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(000)

	Company Exhibit 14 (A)	Adjustments (B)	Adjusted 1975 Test Year (C)
1. Operating Revenues	$76,616	$2,123(a)	$78,739
2. Operating Expenses			

3. Operation and Maintenance			
4. Purchased Power	1,768	-	1,768
5. Fuel	5,127	-	5,127
6. Other	18,897	-	18,897
7. Total	25,792	-	25,792
8. Depreciation	7,779	(571)(b)	7,208
9. Amort. of Inv. Tax Cr-Dr	5,360	-	5,360
10. Amort. of Inv. Tax Cr-Cr	125	-	125
11. Provision for Fed. Income Taxes			
12. Deferred-Liberalized Depr.	2,393	811(c)	3,204
13. Deferred-Kerr	(516)	-	(516)
14. Deferred in Prior Years	(77)	-	(77)
15. Current	(2,302)	1,584(d)	(718)
16. Taxes Other than Income	11,677	(2,321)(d)	9,356
17. Corporation License Tax	1,350		1,350
18. Total Operating Expenses	$51,331	$ (497)	$50,834
19. Utility Operating Income	$25,285	$ 2,620	27,905
20. Amortization of Profit on Debt Reacquired at Discount			114
21. Balance Available for Return			28,019
22. Electric Utility Rate Base			311,439
23. Adjusted Rate of Return Earned at Present Rates			9.00%

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a. Findings 53-56
b. Finding No. 57
c. Finding No. 61
d. Findings 58 and 59

PART D

GAS UTILITY

63. The Commission finds the following natural gas utility rate base:
1975 Test Year (average)

(000)

	12/31/74 (A)	12/31/75 (B)	1975 (C)
1. Depreciated Original Cost			
2. Gas Plant (Exh. 11, line 7)	$ 75,573	$ 80,265	$
3. Common Plant (Exh. 11, line 10)	3,809	4,899	
4. Total Net Plant	79,382	85,164	82,273
5. Adjustments to Net Plant			
6. Adjust Depreciation Reserve	-	228	
7. Total Adjustments to Net Plant	-	228	114
8. Gas Stored Underground			7,884
9. Less: Customer Contributed Capital			
10. Accumulated Deferred Income Taxes			
11. Liberalized Depreciation	480	845	
12. Accumulated Deferred Investment Tax Credits (Pre-1971)	621	574	
13. Customer Advances for Const.	986	1,000	
14. Total Customer-Cont. Capital	2,087	2,419	2,253
15. Plus: Working Capital			
16. Gross Cash Requirements			2,210
17. Credit for Accrued Taxes			(1,310)
18. Materials and Supplies			2,550

19.	Total Working Capital	3,450
20.	Total Gas Utility Rate Base	$91,468

64. An average rate base was utilized in Finding No. 63 for the reasons stated in Finding No. 44.

65. Depreciation reserve has been adjusted to eliminate depreciation claimed on 1975 additions, for the reasons stated in Finding No. 57A. The corresponding expense adjustment is shown in Finding No. 90.

66 Customer-contributed capital has been eliminated from rate base for the reasons stated in Finding No. 49.

67. The computation of required working capital employs the same methodology as was utilized in Finding No. 51 in connection with electric utility rate base.

Revenues and Expenses

68. Applicant's March 12, 1975, Petition requested a gas rate increase of $5.6 million. Under the July 18, 1975, revised Petition, Applicant ultimately sought increased gas revenues of $28.8 million. Of this total request, $22,251,442 was alleged to be required to offset increased costs of purchased gas (Tr. 5798). The remainder was alleged to be required to permit Applicant to recover its increased expenses, largely due to inflation, and to permit Applicant to realize a fair return on its investment.

69. Applicant projected its increased purchased gas costs by utilizing what approximated a 60 percent purchased gas, 40 percent royalty gas mix for delivery at the Aden border point (Exhibit C)

70. Historically, Applicant's gas mix at the Aden border point consisted of 30 percent purchased gas and 70 percent royalty gas, in approximate figures. This ratio approximates the ratio of the Company's owned reserves in the Aden area (Tr. 5653-5654).

71. With the May 14, 1975, amendment of the Aden export license, which had the effect of reducing the annual export authorization to 10 bcf, Applicant's witness Coldiron asserted that the MPC's Canadian subsidiary, Canadian-Montana Gas Company (CMG), would have to change to a 50 percent purchased, 50 percent royalty gas mix in order to avoid the displeasure of the Alberta government. He suggested that such a mix might result in termination of provincial export permits(Tr. 5261). Applicant also contended that this 50-50 mix was essential if Applicant was to avoid being declared a "common purchaser" by the Alberta government, with the result that it would be required to buy gas in the amounts prescribed by the Alberta Oil and Gas Conservation Board (Tr. 5101-5104). Witness Coldiron further testified that he felt Applicant had a moral obligation to Alberta officials to maintain an approximate 50-50 mix (Tr. 5249).

72. An additional constraint which Applicant alleges prohibits it from taking a greater proportion of royalty gas, with a resultant reduction in the rates paid by the ultimate consumer in Montana, is the existence of take-or-pay contracts with its Canadian suppliers Applicant argues that if it were to reduce its purchases and substitute its own gas, then it might be forced to pay for gas not actually taken. Applicant suggests that it would be imprudent to terminate these contracts if the

Commission denied recovery of all costs (Tr. 5259), even though there are cancellation clauses in these contracts which apparently would permit CMG to get out of the take-or-pay arrangements if action by a regulatory agency of the State of Montana rendered the contracts uneconomical (Tr.3160).

73. Witness Hess conceded a gas revenue deficiency of $25,131,000. This figure utilized the rate base advocated by Hess himself, and the 8.75 percent rate of return recommended by staff witness Dr. Wilson (see Schedule 9, Exhibit L). This computation of revenue deficiency utilized Applicant's calculation of its gas supply expense of $22,251,442.

74. On February 11, 1976, the Commission stated, during the hearing in this docket, that it would take official notice of the monthly reports by Applicant of the various sources and unit prices of its gas supply for the test year. Mr. Burke stated, on behalf of Applicant, that Applicant had no objection to this action, and that he assumed that the monthly reports were something the Commission would properly have before it in reaching its decision in this docket (Tr. 5816-5817). On October 6, 1976, the Commission by letter informed all parties that notice would be taken of these same monthly reports. This letter was sent under the mistaken impression that notice had not been taken during the hearing. No objections or statements contesting the materials so noticed were received.

75. To determine the amount of Applicant's gas supply expense, the commission finds that the use of the actual 1975 expense, as evidenced by the monthly reports and normalized to reflect post-May 1975 conditions, is preferable to the hypothetical approach advanced by Applicant in Exhibit C. The use of the actual expense avoids the uncertainties inherent in a hypothetical approach.

76. Applicant's actual imports for the months May through December of 1975 approximated 60 percent royalty, 40 percent purchased gas at the Aden border point. Even with this mix, Applicant encountered none of the problems Mr. Coldiron foresaw for a mix which varied from 50-50. Accordingly, the Commission finds that such a mix is feasible, and that rates established on the basis of such a mix are fair and reasonable.

77. In computing its proposed gas rate increase, Applicant utilized the following projected volumes from its various sources of supply, with associated prices:

	------------ 1975	------------	
	Mcf	4/Mcf	$
Canadian Purchased Gas - Carway	28,867,000	170.70	49,275,969
Canadian Purchased Gas - Aden	5,844,000	142.30	8,316,012
Canadian Royalty Gas - Aden	3,903,000	49.46	1,930,424
Montana Purchased Gas	6,868,000	46.80	3,214,224
Montana Royalty Gas	10,742,000	5.77	619,814
Canadian Fee Gas	480,000	-	-
Montana Fee Gas	-	-	-

Montana Gas Bank	-	-	-
Total	56,704,000		63,356,443

These figures were provided in the response to MCC Data Request No. 57, which was admitted in evidence as Exhibit C at the hearing. The calculation assumes that Applicant's gas inventory remains constant. The total Exhibit C gas supply cost is also contained in Exhibit 15, as revised October 20, 1975, as the sum of royalty cost (line 5, column C) and other gas supply (line 8, column C). The $31,955 amount by which the Exhibit 15 total exceeds the Exhibit C total is a result of expenses incurred in accounts numbers 2807.1, 2807.2 and 2813, under the general heading of "Other Gas Supply Expenses-Wellhead Purchases."

78. A comparison of the gas mix projected by Applicant in Exhibit C with the actual mix for the months May, 1975, through December, 1975, is shown below:

	Applicant Exhibit C (%)	Monthly Reports Actual 8 Months (%)
Carway Purchase Gas	50.90822	53.13711
Aden Purchase Gas	10.30615	7.61865
Aden Royalty Gas	6.88311	11.96211
- Montana Purchase Gas	12.11202	9.83539
Montana Royalty Gas	18.94398	16.75272
Canadian Fee Gas	0.84650	0.69399

79. The actual mix ratios reflected in Finding No. 78 cover only an eight month period of the test year. Normalization of these eight months' supplies to ref1ect a full year's operations yields the following quantities of gas from each source of supply:

Source Amount	(Mcf's at 14.9)
Carway Purchase Gas.........	30,130,876
Aden Purchase Gas	4,320,080
Aden Royalty Gas	6,782,997
Montana Purchase Gas	5,577,062
Montana Royalty Gas	9,499,464
Canadian Fee Gas	393,521
Total......................	56,704,000

80. The volumes shown in the above table exceed the export license limitations imposed by Canadian authorities, and effective in May of 1975. Because of the May reduction in export authorization from 20 bcf to 10 bcf, the January through April sources of supply must be ignored.

81. The normalized sources of supply shown in Finding No. 79 must be I adjusted to take account of the export license constraints effective in May of 1975. Applying the Carway limitation of 28,867,000 Mcf's (Exhibit C) and the Aden limitation of 10,227,000 Mcf's (Exhibit C) to the Finding No. 79 total results in the following normalized sources of supply:

Source	Amount (Mcf's at 14.9 psia)
Carway Purchase Gas............	28,867,000
Aden Purchase Gas..............	3,843,004
Aden Royalty Gas...............	6,033,934
Montana Purchase Gas...........	6,514,235
Montana Royalty Gas...........	11,095,765
Canadian Fee Gas (Aden).......	350,062
Total	56,704,000

Supply requirements in excess of the volumes available to Applicant under the N. E. B.'s order effective May 14, 1975, were assumed to come from Montana purchased and royalty gas in the same ratio as the actual percentages computed from the May through December reports.

82. In order to complete the determination of Applicant's test year gas supply expense, it is necessary to take account of the increased costs associated with the Alberta Natural Gas Pricing Agreement Act of November 25, 1975 (Tr. 5801-5802). This Act resulted in unit costs for Aden purchased royalty and fee gas which differed from those shown in Exhibit C. The new unit costs produced a net annual increased cost of S1,154,084 (Tr. 5804) when applied to the Exhibit C volumes of gas, as projected by Applicant.

83. The unit prices resulting from the Alberta Natural Gas Pricing Agreement Act are as follows:

	4/MCF
Carway Purchase Gas........	170.74
Aden Purchase Gas..........	133.94
Aden Royalty Gas...........	85.44
Montana Purchase Gas.......	46.8
Montana Royalty Gas........	5.77
Canadian Fee Gas...........	50.13

84. The new unit costs resulting from the Alberta Natural Gas Pricing Agreement Act, when applied to the normalized, constrained volumes in

Finding No. 81, result in a net increase from this Act of S85,075 above the total costs contained in Exhibit C for the test year.

85. A total supply input of 56,704,000 Mcf's is required to meet Applicant's test year market of 52,662,315 Mcf's because of such factors as production, transmission and distribution losses.

86. The revenues granted in Order No. 4220A, when applied to the test year market of 52,662,315 Mcf's, are $20,372,000.

87. $22,251,442 of the requested $28,735,406 gas revenue increase consisted of increased gas supply costs (Tr. 5798; Exhibit 8). The Alberta Natural Gas Pricing Agreement Act increases this figure by $85,075, resulting in a total gas supply cost component of the requested increase of $22,336,517.

88. Under Applicant's contracts with interruptible industrial customers, 43.46 percent of the $85,075 increased gas supply cost set forth in Finding No. 87 is already being paid by industrial contract customers.

89. The Commission finds that industrial contract customers are presently contributing approximately $37,000 of revenues over the total revenue figure shown in Exhibit 15.

90. The Commission finds that the following adjustments to gas utility operating expenses are required:

	(000)	
1. Depreciation Expense		
2. Eliminate Depreciation Expense on 1975 Additions		
3. Montana Power Company	$ 182	
4. Canadian-Montana Gas Company Ltd.	13	
5. Common	33	
6. Total Adjustment		$(228)
7. Real Estate & Personal Property Taxes		
8. Included in Exhibit 15	$2,954	
9. Company Revised Estimate (12/19/75)	2,522	
10. Adjustment		(432)
11. Eliminate One-Half of Taxes on Full Year 1975 Additions		(339)
12. Total Adjustments to Taxes Other than Income Taxes		(771)
13. Other Gas Supply		
14. Canadian Supply		

	Increase in Royalty Expense	$ 200	
	Increase in Ministry Expense	30	
	Total Canadian Increase	230	
15.	Montana Supply		
	Decrease in Montana Expenses	(145)	
	Total Adjustment to Gas Costs		85
16.	Income Taxes		Federal
17.	Adjustments to Other Taxes	$ (771)	
18.	Income Tax Effect of Adjustments to Other Taxes		370
19.	Adjustments to Montana Gas Expense	(145)	
20.	Income Tax Effect of Adjustments to Other Taxes		70
21.	Adjustments to Canadian Gas Expense	230	
22.	Income Tax Effect of Adjustments		
23.	Credits Resulting from Additional Royalty Expense		(75)
24.	Effect of Increase in Ministry Costs		(12)
25.	Adjustment to Operating Revenues		
26.	Increase from Contract Customers	37	
27.	Tax Effect of Increased Revenues		18
28.	Total Tax Adjustment		371

91. The depreciation expense on 1975 plant additions has been eliminated for the reasons stated in Finding No. 57A.

92. Real estate and personal property taxes have been adjusted to eliminate taxes on one-half of 1975 plant additions. This adjustment is necessary in order to make tax expense correspond to average rate base adjustments.

93. Other gas supply costs must reflect the revised expense computed in Findings 75 through 87.

94. Income tax expense adjustments must be made to reflect adjust meets to real estate and personal property taxes, to treat the adjustment to Applicant's gas supply costs determined in Findings 75 through 87, and to take account of the increased industrial revenues, as shown in Finding No. 89, which are already being collected.

95. The following table summarizes the Commission's findings as to revenues and expenses:

(000)

	Company Exhibit 15 (A)	Adjustments (B)	Adjusted 1975 Test Year (C)
1. Operating Revenues	$ 65,881	$ 37	$ 65,918

2. Operating Expenses			
3. Operation & Maintenance			
4. Other Gas Supply	60,838	85	60,923
5. Other	15,494		15,494
6. Total	$ 76,332		$ 76,417
7. Depreciation	3,080	(228)	2,852
8. Amortization of Investment Tax Cr-Dr	450		450
9. Amortization of Investment Tax Cr-Cr	59		59
10. Provision for Federal Income Taxes			
11. Deferred - Liberalized Deprec.	366		366
12. Current	(6,153)	371	(5,782)
13. Amortization of Property Losses	72		72
14. Taxes Other than Income Taxes	3,714	(771)	2,943
15. Corporation License Tax	50		50
16. Total Operating Expenses	$ 77,852	(543)	$ 77,309
17. Utility Operating Income	(11,971)	(580)	(11,391)
18. Amortization of Profit on Debt Reacquired at a Discount			38
19. Balance Available for Return			(11,353)
20. Gas Utility Rate Base			91,468
21. Adjusted Rate of Return Earned At Present Rates			

PART E

REVENUE REQUIREMENTS

96. The Commission finds that the additional revenues required in Applicant's electric operations are $2,069,000. This amount is computed as follows:

(000)

Adjusted Rate Base	$311,839(a)		
Required Rate of Return	9.33%(b)		
Required Return		$29,095	
Amount Available for Return Under Present Rates		28,019(c)	
Income Deficiency			$1,076
Revenue Deficiency			2,069(d)

97. The Commission finds that the additional revenues required in Applicant's natural gas operations are S26,862,000. This amount is computed as follows:

(000)

Adjusted Rate Base	$91,468(e)	
Required Rate of Return	9.68%f	
Required Return		$ 8,854
Balance Available for Return After	>	
Tax Loss Carry Back Adjustment	(11,353)(g)	
Tax Loss Carry Back Adjustment	6,239	

Balance Available for Return Before	
Tax Loss Carry Back Adjustment	(5,114)
Income Deficiency	13,968
Revenue Deficiency	$26,862(h)

a. Finding No. 41
b. Finding No. 40
c. Finding No. 62
d. This amount recognizes an income tax obligation of 48% for rate making purposes; however, actual accumulated deferred income taxes have been deducted from rate base in Finding No. 41.
e. Finding No. 63
f. Finding No. 40
g. Finding No. 95
h. This amount recognizes an income tax obligation of 48% for rate making purposes; however, actual accumulated deferred income taxes have been deducted from rate base in Finding No. 63.

PART F
RATE STRUCTURE
cost of Service Studies

98. Applicant presented cost of service studies for the test year for both the electric and gas utilities. The test year studies resulted from projections of base studies which had been prepared beginning in 1973.

99. As Mr. Richard Pierce of Ebasco Services, Inc., the consulting firm primarily responsible for the preparation of these studies, testified, a cost of service study is:
"... a procedure for the allocation of plant investment, revenues and expenses to classes of service. When it is completed a rate of return on the investment allocated to each class of service may be determined." (Tr. 2141)

100. A valid cost of service study is an important tool in determination of just and reasonable rates for each class of a utility's service. It allows the regulatory agency to compare the contributions made by each class to a utility's over-all revenue requirement. The agency can then proceed, on the basis of the evidence before it, to establish class rates which provide a uniform return, or which provide a return above or below the average return for all classes of service. If the decision is made that the return earned from the non-residential class, for example, should exceed that from residential sales, then the agency has the responsibility of justifying that decision on the basis of the record which is before

it.

101. Unfortunately, the studies which Applicant introduced do not permit the Commission to proceed in this manner. These studies were subjected to extensive criticism at the hearing in this docket, and the Commission finds that much of that criticism was valid.

102. The manner in which costs are allocated in a cost of service study depends, in large part, on the load characteristics of a particular class. The amount of energy used by a class and the times of the day and year when energy is used, are the key determinants of the costs imposed by any one class on the utility. If valid load information is lacking, then the cost allocations employed in a study may produce results which bear little resemblance to actual circumstances.

Electric Cost of Service

103. There is a substantial amount of confusion in this record as to precisely: what electric load data was utilized by Ebasco. It is clear that the residential, and small general service load data was "synthesized" from a study prepared in 1958 of Pacific Power and Light Company's Oregon service area (Tr. 2361-2364; 2903). To determine the load factor for the industrial contract customer class, Pierce said:

"Montana Power made an estimate of the kilowatt hour sales, and the demands at the customer's meter." (Tr. 2371)

On rebuttal, however, Mr. Crespo of Ebasco Services testified that the industrial contract customer portion of the 1973 study had utilized "actual, Montana Power Company 1973 load information." (Tr. 4931)

104. Regardless of what load information was used for industrial customers, the information for residential and general service customers was that of the 1958 Pacific Power and Light Company study, as "synthesized." As Mr. Doty pointed out in argument, the MPC's Petition asks that 77 percent of the requested electric rate increase

be absorbed by the residential and general classes.
Absent convincing evidence of the propriety of using "synthetic" load data, and in view of the uncertainty surrounding the industrial load data employed by Ebasco, the Commission finds that the electric cost of service study presented in this docket is not a reliable beginning point for the establishment of just and reasonable rates

105. The proposed uniform percentage increase on electric rates charged all classes of customers would, without justification in the record, create an even greater disparity in rates paid by different classes of customers than now exists.

106. A more reasonable approach, in the absence of valid allocated cost of service studies, is to spread the required revenue increases determined in Findings 96 and 97 on a uniform, constant cents per Kwh basis to the general service and industrial classes. Because of the special conditions inherent in residential service, the rate structure for that class is treated separately below. However, the contribution of the residential class to the electric utility revenue requirement has been computed on a volumetric basis, in the same manner as for general service and industrial classes.

Lifeline

107. The Center for the Public Interest (CPI) urged the Commission to adopt a lifeline rate structure for Applicant's residential electric service. As Mr. Rick Applegate indicated, lifeline is an approach to rate structure which identifies the amount of electricity necessary to sustain a simple life style, and prices this basic block of electricity at rates which are affordable by low-income consumers. The CPI proposal also incorporated an inverted rate structure for all electricity used beyond the basic block in order to encourage conservation (Tr. 3672).

108. Dr. Eugene Coyle, an expert witness for the CPI, suggested that the basic energy block for a lifeline rate structure would be determined by selecting appliances considered to be necessities, and summing the monthly Kwh consumption of the group (Tr. 3964).
109. Geoffrey L. Brazier, the Consumer Defender of the Montana

Consumer Counsel, summarized the concerns which the Legislative Consumer Committee had with a lifeline rate structure. Among these were the possibility that lifeline might inadvertently benefit the affluent at the expense of the poor. Additional concerns were said to be possible penalties to large families and communities without natural gas service (Tr. 4079-4082).

110. The Commission feels that these and other questions raised by the lifeline proposal were not adequately addressed on this record. The Commission is, however, sympathetic to the goals of lifeline proponents. The method selected for spreading the increase to residential consumers represents, it is felt, the best means of easing the impact of the increase on low income, low volume consumers which is possible on this record.

Residential Rate Structure

111. Applicant proposed the following electric rate structure for residential customers:

First 20 Kwh or less per month....................	$1.71
Next 80 Kwh per month............................	5.434 per Kwh
Next 100 Kwh per month...........................	3.804 per Kwh
All additional kwh per month......................	1.904 per Kwh

This rate structure has three components: (a) a minimum service charge, (b) steeply declining blocks to a total consumption of 200 Kwh, and (c) a flat rate charge for consumption in excess of 200 Kwh.

112. The justification for this structure, as well as the structures proposed for other classes, was not developed at length on the record. Mr. Heidt, who designed the proposed rate structures, referred to their "long history" (Tr. 1957), apparently recognizing that declining blocks are the traditional rate structure in the utility industry. He also referred to "the proprieties set forth under Order 4068" (Tr. 1957) in an attempt to explain why declining blocks are proper. Those "proprieties," however, are not a part of this case, and the Commission is left to infer the basis for the proposed structures.
113. Applicant's proposed charge of $1.71 is, in effect, a minimum bill, as it applies to consumption of 20 Kwh or less per month. Traditional rate '2'" design theory would dictate a structure designed to recoup customer-associated costs in the first block of service. These costs, including metering, distribution, billing, and other

customer-specific costs, are incurred whether or not electricity is used. The Commission finds that the proposed structure and underlying cost information demonstrated the propriety of a minimum monthly charge.

114. Applicant's structure utilizes two additional consumption blocks to reach the 200 Kwh level. It can be inferred that the revenues collected in these blocks serve to defray operation and maintenance expense, and perhaps generate a contribution to Applicant's return. The remaining residential block, for all service in excess of 200 Kwh per month, can be viewed as an energy charge, which serves to cover production costs and return on investment.

115. The Commission finds that in the absence of a comprehensive and valid cost of service study that a reasonable residential rate structure should meet the same initial block cost recovery criteria indicated by the Applicant's structure. The Commission adopts a structure incorporating a minimum monthly service charge and a two step energy charge based on the current cost criteria of the Applicant. The Applicant's billing frequency permits equalization of current revenues in the initial 200 Kwh block.

116. Witness Wilson proposed that the Commission follow an approach which he stated was "consistent with both the general philosophy of lifeline rates as well as over-riding cost considerations ..." (Tr. 3150). He suggested "tilting" any electric modification to benefit the initial blocks in the various rate categories (Tr. 3150). He concluded that:

"This will result in a general flattening of rates and comparatively lower bills for small volume customers as well as a movement in the direction of a uniform energy charge which would be justified on the basis of pure marginal cost considerations." (Tr. 3151)

117. Consistent with the "tilting philosophy" suggested by Wilson, the Commission finds that the increased revenue requirement of the Applicant, properly applicable to the residential class, should be applied only to residential consumption in excess of 200 Kwh per month. This allocation of responsibility is based on the substantial

investment in additional generating facilities at Colstrip 1 which was required to meet increased electric demand in Montana.
This structure recognizes that energy prices must reflect the marginal costs associated with escalating consumption.

Natural Gas Rate Structure

118. The Ebasco natural gas cost of service study allocated production supply costs to customers 50 percent on the basis of class coincident peak responsibility, and 50 percent on the basis of class commodity requirements (Tr. 2171). Mr. Pierce stated that this particular allocation formula, which he called "a modified, modified Seaboard," was justified because of prior acceptance by the Federal Power Commission, and because of Applicant's take-or pay arrangements with Canadian suppliers (Tr. 2210). He stated that he disagreed with the rationale employed by the Federal Power Commission it its Opinion No. 731, where production and gathering costs were classified as a commodity cost.

Although he acknowledged that the Federal Power Commission had based its decision on the national shortage of natural gas, he termed this a "price" decision as opposed to his costing approach (Tr. 2309-2310).
119. Mr. Pierce acknowledged that his 50-50 allocation scheme had the effect of treating part of purchased gas costs as a demand cost (Tr. 2214-2215). The impact of this treatment is that small volume gas users are depicted by Pierce's study as having been the source of increased costs actually attributable to large volume users.

120. Both Dr. Wilson and Mr. Lewis, the expert witness for the Executive Agencies of the U. S. Government, stated that they favored more of a volumetric approach to gas cost allocations (Tr. 3151; 4721). This approach, it was argued, would encourage conservation (Tr. 3153), and would lead to a depiction of large volume consumers as yielding to Applicant a rate of return lower than that shown by Mr. Pierce (Tr. 4722).

121. The Applicant's natural gas supply situation is a matter of considerable concern to the Commission. The heavy dependence upon the Canadian sources at Aden and Carway and the continued uncertainties associated with the export licenses, dictate that the Commission

institute a rate structure for natural gas that will encourage conservation.

122. It is readily apparent from an analysis of gas utility revenue requirements that the increased natural gas rates to all consumer classes is basically the result of commodity price escalations. The natural gas supply or commodity expense comprises the overwhelming part of the total natural gas utility expenses, as illustrated on Applicant's Exhibit No. 15. The Commission finds that the volumetric or commodity allocation of the rate increase to all classes of consumers is clearly dictated.

Great Falls Gas

123. Great Falls Gas Company (GFG) contends in its brief that the rate which it is charged is excessive, when compared to the other companies in the "other utility" category of Applicant's customers. GFG also claims that a monthly customer charge which it is required to pay Applicant is discriminatory, as GFG is the only "other utility" with such a charge as a part of its rate structure.

124. To the extent the cost per mcf to GFG exceeds the average cost in the "other utility" category, the Commission finds that the excess is attributable to the customer charge which GFG pays Applicant. Mr. Heidt affirmed on the record that no other utility customer is required to pay a customer charge (Tr. 2081). No justification for the singling out of GFG for this treatment was offered.

Employee Discounts

125. Applicant's proposed schedules include discounts of 25 percent on natural gas sales and 40 percent on electric sales to full-time permanent employees. Mr. Gordon Mahood of the International Brotherhood of Electrical Workers explained that these discounts were the subject of collective bargaining.

Although the Commission recognize- the view that employee discounts should be treated like any other fringe benefit, it believes that the limited nature of our energy resources places these discounts in a special category. Scarcity of energy supplies leads the Commission to believe that any discount which might lead to encouragement of consumption demands closer scrutiny. As a result, the Commission will continue to obtain information from all regulated utilities in the interest of determining whether continued discounts are justified, and whether the amount of the discounts is excessive.

CONCLUSIONS OF LAW

1. The rate bases determined in Find of Fact No. 41 for the electric utility, and Finding of fact- No. 63 for tht2 yes utility reflect original cost depreciated values. These values comply with the requirement of R. C. M. 1947, Section 70-106, that the value placed upon a utility's property for ratemaking purposes "shall not exceed the original cost of the property."

2. R. C. M. 1947, Section 70-106, states in part that "The Commission is not bound to accept or use any particular value in determining rates ..." Although Applicant advocated the use of undepreciated original cost values, the Commission has utilized original cost depreciated values as they reflect Applicant's present net investment in its properties. In view of the broad discretion granted the Commission by the legislature, this choice of a valuation method is proper.

3. Average rate base is an appropriate means of measuring the value of Applicant's properties at risk during the test period. In addition, the use of average rate base values better match test year revenues and expenses to the properties which produced them than do end of test year values. Applicant made no effort to adjust its test year revenues and expenses to year-end levels, and, accordingly, the use of average rate base figures is appropriate and essential to a consistent treatment of Applicant's test year operating results.

4. The adjustments to Applicant's electric rate base figures discussed in Findings 42 and 46 are necessary because both the eliminated acquisition adjustments and the fair value Mystic Lake valuation bore no relationship to the original cost of Applicant's properties when first dedicated to public use.

5. The exclusion of customer-contributed capital from rate base is proper as ratepayers should not be forced to provide a return on funds which they have furnished a utility. The exclusion from rate base of pre-1971 accumulations of deferred investment tax credits will not result in loss to Applicant of the right to claim these credits.
6. The Commission's allowance for working capital is necessary to permit Applicant to meet its obligations before cash from ratepayers is available for this purpose. The amounts allowed in both the electric and gas rate bases are sufficient for this purpose.

7. The adjustment discussed in Findings 53 and 54 for revenue from surplus sales of electric power to other utilities is proper because the adjusted price per kilowatt is much closer to the prices actually received by Applicant in the test year than was Applicant's estimated price.

8. The adjustment in Finding No. 55 to non-jurisdictional sales is necessary to prevent subsidization by jurisdictional ratepayers, and as an incentive to Applicant to seek compensatory rates on these transactions.

9. The adjustment to Applicant's gas supply cost discussed in Findings 75 through 84 is an accurate reflection of Applicant's actual test year costs.
10. The rate of return allowed in this order meets the constitutional requirement that a public utility's return must be "commensurate with returns on investments in other enterprises having corresponding risks and sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." Federal Power Commission v. Hope Natural Gas Company, 320 U. S. 591, 603 (1944).

11. In the absence of demonstrably valid allocated cost of service studies, which both reflect actual load information and employ supportable cost allocation formulae, the volumetric rate increases and the residential rate structure authorized herein are justified.

12. The exaction of a customer charge from Great Falls Gas Company is

discriminatory since no other utility customer is assessed such a charge, and no basis for this treatment was demonstrated.

13. Applicant's proposed changes in its service regulations, with the exception of the proposed rule governing undergrounding of service lines in new subdivisions, are accepted. The undergrounding rule is no longer needed as the Commission has adopted its Rule No. 38-2.14(1)-S1420, which deals with the same subject matter as the requested regulation.

14. R. C. M. 1947, Section 70-113, requires that the Commission conduct a hearing before it approves a rate increase in a schedule generally affecting consumers. Accordingly, the requested tax adjustment and purchased gas adjustment clauses must be denied because these clauses would result in automatic increases.

15. The rates and charges authorized herein are just and reasonable.

16. The rate structures authorized herein are non-discriminatory.

ORDER

THE MONTANA PUBLIC SERVICE COMMISSION ORDERS THAT:

1. The Montana Power Company shall file rate schedules effective for services rendered after March 1, 1977, which reflect revenue increases of S2,069,000 on electric service, and $26,862,000 on gas service, which includes amounts already awarded as temporary increases in Orders 4220A and 4220B.

2. a. The increased electric revenues authorized herein shall be distributed to Applicant's classes of service on a uniform cents per Kwh basis. However, Applicant shall file revised residential electric rate schedules incorporating a S1.70 monthly service charge and an energy charge of 3.18 cents per Kwh for consumption from 0 to 200 Kwh's and 1.60 cents per Kwh for energy in excess of 200 Kwh.

b. The increased natural gas revenues authorized herein result from the following component increases, and shall be distributed on the basis of the table below:

Class	Cost of Gas	Inflationary Increase	Total/Class

Residential	$ 6,381,083	$1,394,140	$ 8,275,223
Non-Residential	5,416,814	1,097,472	6,514,286
Small Utilities	330,876	67,037	397,913
Industrials	9,707,744	1,966,834	11,674,578
Total	$22,336,517	$4,525,483	$26,862,000

3. Applicant shall continue to file monthly reports of its sources of natural gas supply, and the prices at which this supply is obtained.

4. Applicant is ordered to immediately take steps to retain an independent accounting firm acceptable to this Commission for the purpose of undertaking a determination of the original cost of Applicant's hydroelectric properties when first devoted to public use.

5. Applicant shall file revised schedules incorporating the changes in its service regulations approved herein.

6. The $5,939,000 net acquisition adjustments eliminated from electric rate base in Finding No. 42 represent an actual outlay of funds by Applicant's shareholders. Because these funds were actually expended, Applicant should be permitted to recapture this investment. Accordingly, and in order to avoid the need for revision of the Exhibits and Testimony on file in Docket No. 6454, this sum shall be amortized over a twenty year period beginning in 1978. On January 1, 1978, Applicant shall file revived electric schedules which reflect a 5296, 950 increase in revenues, spread on a constant cents per Kwh basis to all classes of its electric customers.

7. All motions and objections not ruled upon at the hearing are denied.

8. The natural gas rate schedules shall reflect the elimination of the Great Falls Gas Company customer charge, with the resulting revenue deficiency to be made up by all classes of customers on a uniform cents per mcf basis.

DONE IN OPEN SESSION at a meeting of the Montana Public Service Commission held February 22, 1977 by the vote indicated below.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION.

Gordon E. Bollinger, Chairman

P. J. Gilfeather, Commissioner

Thomas J. Schneider, Commissioner

George Turman, Commissioner
Voting at a later time to concur with the majority

James R. Shea, Commissioner
Concurring as to electric decision,
Dissenting from gas decision.

ATTEST:

Gail E. Behan
Secretary

(SEAL)

NOTICE: You are entitled to judicial review of this Order. Judicial review may be obtained by filing within 30 (thirty) days from the service of this Order a petition for review pursuant to Section 82-4216, RCM, 1947.

I concur in the decision of the Montana Public Service Commission pertaining to the electric portion of the Montana Power rate case, Docket No. 6348.

James R. Shea, Commissioner
District 4

I dissent to the decision of the Montana Public Service Commission pertaining to the gas increases. The reasons for my dissent on the gas portion of Docket No. 6348 are as follows.

James R. Shea, Commissioner
District 4

Regulatory decisions must take into account their immediate and long term impact on residential, commercial and industrial accounts.

It is interesting to note that an excess of gas now in Canada has resulted in wells being capped and the owners are waiting for increased prices.

One of the reasons that additional gas resources have been increased is because industrial plants are converting to other fuel. A price increase has already caused some industrials to convert to other fuels. If the price of Canadian gas is permitted to rise without strong regulatory and buyer resistance such increases might result in a serious problem. Many people will find the cost of fuel too burdensome to bear.

The various Commissions and other governmental agencies throughout the United States including the National Congress and the Montana

Legislature have not sufficiently addressed the total energy supply and its cost problems as they relate to residential, commercial and industrial use and price. I believe that regulatory commissions should give resistance to price increases. If "pass through" costs are going to be permitted at all levels then where can the consumer of the product obtain any representation of whether or not costs are justified, fair and equitable?

More and more increases will therefore follow and the suppliers of the product will obtain "all the traffic will bear". This will be at the expense of the ultimate consumer. In this so called purchase agreement, the ultimate consumer does not have any input in the price structure and must bear the burden of paying prices that might not be justified or equitable. Most gas users have become captive to the gas industry.

In December of 1976, Sheik Ahmend Zaki Yamani of Arabia resisted oil price increases in the oil producing export countries (OPEC). Sheik Yamani held to a five (5%) percent increase for oil and fuel.
His strong efforts resulted in a sizeable reduction of the proposed increase in oil from fifteen (15%) to five (5%) percent.

This proves to me that something can be done and must be done. Gas prices from Canada are directly related to the cost of oil imports. While OPEC policies and prices are not in the record on Docket No. 6348, in my opinion they are indeed part of a worldwide record that is being now made in international economics and is being spread into the homes of all persons having to use fuel.
Energy producing countries and companies have collaborated to get as much [or their oil products as possible. Unless the ultimate consumers of the "pass through" object to these increases either by themselves or through the various governmental agencies that represent the public, the increased costs will be heavily and constantly thrust upon the consumers. Senior citizens and others on fixed incomes will find such increases exceedingly worrisome and burdensome. Who then should speak for our senior citizens and ,or those unable to meet costs?
While an official record of a hearing itself expresses a certain responsibility to the decision makers, we must also remember that these are times of very grave concern. Equity demands that we recognize a very serious obligation that of protecting our senior citizens and of all those unable to meet the escalation of fuel costs. Fuel is a vital necessity of providing needs to many for the very sustenance of life.
This decision has not been made in haste. Because of the National Energy Crisis and the price of gas is certainly a part of that crisis I believe that every public service commissioner should speak out for the people. The other Montana Public Service Commissioners have given this same problem of equity a great amount

of time and consideration and I respect their final decision. However, in view of the foregoing I must dissent to the gas order of Docket No. 6348.

James R. Shea, Commissioner
District 4